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Dear Dominic

Electricity Balancing Significant Code Review: Draft Policy Decision

Thank you for the opportunity to provide our view on your Draft Policy Decision on the Electricity Balancing Significant Code Review (EBSCR). This response is provided on behalf of National Grid Electricity Transmission plc (NGET) and is not confidential. In the UK our primary duties under the Electricity Act are to develop and maintain an efficient network and to facilitate competition in the generation and supply of electricity. Our activities include the residual balancing of the electricity system in real time.

This response consists of two main sections. The first section, contained here, is a high level summary of:

- the important principles that we consider to underpin the policy area of electricity balancing;
- our views on each of the proposed policy options;
- our preferred package choice; and
- our thoughts regarding implementation.

The second section, attached to this document as Annex 1, contains more detailed responses to the specific consultation questions.

Principles

We support measures that increase the extent to which parties are incentivised to balance their own positions ahead of Gate Closure. Reforms to more accurately reflect the marginal value of energy and the price of System Operator (SO) actions in the cash-out price can be an appropriate way of doing this. This has always been a fundamental objective of the electricity market since the implementation of the New Electricity Trading Arrangements (NETA) but will only increase in importance as plant margins diminish and the generation mix becomes more inflexible and intermittent. This is also important given our role as residual balancer as, with the volume of SO actions likely to increase in the future, the incentives on parties to balance their positions will become increasingly critical.

In addition, it is important that overall costs to consumers are fully considered against the corresponding benefits (e.g. that no unnecessary balancing costs are introduced) and that proposed reforms do not introduce unintended effects in terms of competition (e.g. increased barriers to entry). This can be done by ensuring that the efficiency of market arrangements is prioritised when policy decisions are being made and that risks (i.e. both between market participants and end consumers and between different types of market participants themselves) are always assigned to those parties that are best suited to manage them. It is also important from the point of view of secure operation of the transmission system that incentives are not introduced that might cause market participants to undertake unilateral actions within balancing timescales that may complicate the SO's ability to take actions to balance the system.

These points apply not only to the electricity balancing regime in isolation but also when interactions with the gas regime and Electricity Market Reform (EMR) are evident.

Finally, there appears to be a slight prevalence when considering the impact of the proposed policy reforms to focus on a short market over winter peak. Whilst this is clearly an important consideration in terms of security of supply, we feel that it is also important to consider further[1] the impact the proposals may have on parties during summer minimum periods. This is because low demand and inflexible generation could lead to bids being required for energy purposes on intermittent plant (e.g. wind) and potentially to negative imbalance prices.

Policy options and preferred policy package

With this in mind, our views on the proposed policy options are as follows:

Policy Consideration	**NGET view**
More marginal main cash-out price (reducing the value of Price Average Reference or PAR from its current level of 500MWh)	We support a more marginal cash-out price and, whilst we agree that PAR1 is the most efficient theoretical solution, propose an interim period at PAR50 to enable a more phased approach.
Attributing a cost to non-costed actions ("Value of Lost Load" or "VoLL" pricing)	We agree that a cost should be attributed to Demand Control actions and that this should be reflected in the cash-out calculation. We are comfortable that demand disconnection should be priced at VoLL but consider that voltage reduction should be priced at a lower level to reflect the fact that it has a lesser impact on end consumers.
Improving the way reserve is costed	We agree that the current calculations applying the Buy Price Adjustor (BPA) and Sell Price Adjustor (SPA) can be improved and support the use of the Reserve Scarcity Pricing function in order to better signal to the market when margins are tightening.

[1] We note that increasing wind on the system and negative imbalance prices is mentioned in section 4.9 of the Impact Assessment.

Single or dual cash-out prices	When combined with the other three options above, we support a move to a single cash-out price provided that sufficient consideration is given to ensuring no intentional deviation from Final Physical Notifications (FPNs) takes place post-Gate Closure.
Policy Package	**5** **(albeit with a phased approach to the reduction in the level of PAR and pricing voltage reduction at a lower level than demand disconnection)**

Implementation

We believe strongly that a staged approach to implementation of elements of the chosen policy package is appropriate. This is because both the complexity and the level of detail required from the Authority to prescribe detailed policy directions vary between the individual policies. For example, both a reduced PAR and a change from dual to single imbalance pricing could be implemented quickly, easily and with limited costs if it was progressed in timescales and a manner preordained by the Authority (i.e. in such a way that there is no requirement for any additional industry decision-making). Therefore the benefits of these policies could be realised much sooner, for example by winter 2014/15. However, the same is not true of the other policy considerations as these will require significant industry involvement if implementation risks are to be mitigated.

Therefore, we would propose that, in the event that any PAR reduction or move to single imbalance pricing is determined, the Authority direct a BSC modification to be raised immediately as part of the Final Policy Decision. Furthermore, a deadline for implementation should also be set at this point to avoid delays creeping into proceedings.

If you wish to discuss the content of this response further, or have any queries, please contact Alex Haffner on 01926 65 5838 or at alex.haffner@nationalgrid.com in the first instance.

Yours sincerely,

Mike Calviou
Director of Transmission Network Service

ANNEX 1 – Response to questions set out in the Draft Policy Decision

Question 1: Do you agree with our proposal to make cash-out prices more marginal?

We agree that, by dampening cash-out price signals, the current Price Average Reference (PAR) value of 500MWh is likely to weaken the incentives for market participants to balance their energy positions and invest in flexible generation capacity. This also provides a diluted signal to participants, with those exacerbating the overall energy imbalance position not facing the full costs of balancing actions taken by the System Operator (SO). Therefore we believe that cash-out prices should be made more marginal to improve the incentive to balance.

Furthermore, we believe that this change should be implemented as soon as possible following the Final Policy Decision next year (e.g. this decision could perhaps direct that a BSC Modification be raised to reduce the level of PAR to a volume that Ofgem determine and also include a set implementation date). This is both because we feel that the move to a more marginal cash-out price can offer benefits for winter 2014 and that the system changes required to reduce the level of PAR are minimal.

In the P217 Authority Decision it states that "*The trigger for reducing PAR may be a track record of non-polluted cash-out prices under P217A, improved access to shape and balancing energy for smaller players through increased within-day liquidity (or other mechanisms), reduced cash-out price spreads which may result from the former or an amendment to the reverse price methodology, or a combination of all of these.*"

We believe that the track record of non-polluted cash-out prices since P217A was implemented in 2009 has been demonstrated by the results of the SO Flagging as presented in the annual reports and that, as set out in Ofgem's recent consultation on the "Secure and Promote" Licence Condition, near-time liquidity has improved considerably over the last few years. We do not see that moving to a more marginal level of PAR is likely to have a detrimental impact on near-time liquidity as, if anything, it should provide an incentive for parties to carry out more trades closer to real time (i.e. in order to mitigate exposure to more marginal imbalance prices).

Question 2: Do you agree with our rationale for going to PAR1 rather than PAR50? Are you concerned with potential flagging errors, and would you welcome introduction of a process to address them ex-post?

PAR1 or PAR50

Cash-out prices based on either PAR1 or PAR50 provide powerful signals to parties to balance their positions prior to Gate Closure and we believe each would represent an improvement to the current 500MWh level. Economic theory suggests that a fully marginal cash-out price of PAR1 presents the most efficient solution as it delivers price signals that fully reflect costs borne by the SO. However, a move from PAR500 to PAR1 represents an extreme change that we would be cautious of taking in a single step.

As noted in Chapter 5 of the Policy Decision detailing interactions, along with the other policy reforms proposed under the EBSCR, there are several ongoing regulatory developments that will present changes to current market arrangements. Whilst the industry is likely to understand the outcomes each of these changes is intended to bring about in isolation, appreciation of how they will interact to influence participant behaviour is less predictable. Implementing such significant changes concurrently has the potential to modify incentives in ways that have not been anticipated. Therefore, whilst we think that PAR1 is the right volume to aspire towards, we would suggest applying a staggered approach to implementation; starting with an interim volume such as PAR50 to allow an assessment of the extent to which behaviour changes in line with expectations.

We note that Ofgem are proposing a staggered approach to the increase in the Value of Lost Load (VoLL) by moving first to a value of £3000/MWh before arriving at the decided figure of £6000/MWh. We suggest that a similarly phased implementation could be beneficial to the treatment of PAR. This should be established using a pre-determined transition (i.e. move to PAR1 after a set time period) so that there is no uncertainty contained in the Final Policy Decision.

This staggered approach would also mitigate any risks to market participants associated with the implementation of more marginal cash-out prices ahead of winter 2014 that we propose in our response to Question 1, as it allows time for industry to better prepare for the move to fully marginal pricing.

SO Flagging errors

There have been recent occurrences where imbalance prices have been affected by the mis-flagging of Bid Offer Acceptances (BOAs). The most notable such incident occurred on 26/04/13 and saw a drop in System Sell Price (SSP) from £37/MWh in Settlement Period (SP) 30 to £19/MWh in SP31 and then to £-54/MWh in SP32 before returning back to £37/MWh in SP33. We acknowledge that this is a significant impact and also that its effect would have been even more notable under a reduced level of PAR.

Nonetheless, we believe that the record of SO-Flagging since the implementation of P217A has demonstrated that it is rare for BOAs to be mis-flagged and rarer still for these to feed through into system prices. However, notwithstanding the general good performance since the implementation of P217A, we would advocate changes to current arrangements to facilitate post-event corrections of mis-flagged actions. Accordingly, we will be proposing changes to Special Condition C16 of the Transmission Licence to allow flagging of BOA actions to be corrected ex-post (the current System Management Action Flagging (SMAF) methodology does not allow for ex-post correction). In conjunction with this, we have also raised a Change Proposal with Elexon to allow these ex-post corrections to be made both now and in the future (e.g. when the new Electricity Balancing System (EBS) goes live).

Whilst we are aware that some parties may oppose the idea of changing SO-flagging (and hence indicative imbalance prices) ex post, we believe that the benefit provided by doing this outweighs the potential disadvantage of reducing certainty of imbalance prices – i.e. this would mean that initial imbalance prices (i.e. those published close to real time) could be subject to change in the days immediately following the relevant settlement period. This is because we believe such ex post changes (similar to treatment of manifest errors) would be expected to happen rarely and, in any event, the market would be notified of the mis-flagged action as soon as it was identified.

The proposed change to the SMAF methodology will be consulted on as soon as the current C16 consultation[2] regarding the new Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR) has concluded. If there is agreement amongst industry stakeholders and the Authority regarding the merits of post-flagging correction, we anticipate that the change to the SMAF methodology could be made by April 2014. In addition to this, provided that the changes to Elexon's systems could be implemented in the June 2014 system release, the ability to correct mis-flagged BOAs ex-post should be available by the time a BSC modification to change PAR could be implemented.

Question 3: Do you agree with our proposals for pricing of voltage reduction and disconnections, including the staggered approach?

For reasons of clarity, we have split the response to this question into the constituent parts set out in the consultation document.

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[2] This consultation proposes changes to a number of documents including the SMAF methodology.

VOLL pricing: setting the cost of voltage control and disconnections

It is our opinion that VoLL is a very subjective figure in relation to electricity and that it varies significantly across the industry. As was highlighted in the National Grid Gas (NGG) response to the Gas SCR, we have some concerns with the introduction of an administered VoLL. To begin with, a true reflection of VoLL should ideally be represented in individual supply contract negotiations and we believe an administered VoLL reduces the incentive on end consumers to determine a meaningful VoLL price. In addition, the use of a pre-determined VoLL carries the risk that it may distort the operation of the market by setting a “target price” for both supply and demand side, reducing the incentive for consumers to ‘sign up’ for interruptible contracts.

That said, the process used to establish the figure of £17,000/MWh in the London Economics report appears to be as thorough as is likely to be achieved in the circumstances. However, the value of £6000/MWh appears to be slightly less robust and instead appears to have been based on a number of pre-determined points such as ‘being greater than the prices bid for Demand Side Response (DSR) by large Industrial and Commercial demand so as to continue to learn where their natural VoLL lies’. Whilst some of these points appear to be valid, it is difficult to state that they actually reflect any one consumer’s ‘Willingness to Pay’ and could potentially lead to policy inconsistencies.

In terms of the proposed phased approach (i.e. using a value of £3000/MWh initially), we believe that this is a sensible policy and one that should be replicated under the PAR aspect of the SCR for the same reasons as quoted for VoLL (i.e. to provide parties with a “soft landing” to help adapt to the new arrangements).

Including Demand Control actions in the cash-out price

In principle, we are supportive of incorporating a cost associated with Demand Control actions (i.e. both voltage reduction and disconnections) into the cash-out price as we do not believe that these should be considered free actions. In addition, whilst the likelihood of these actions being required under the current regime is low, including Demand Control actions in the cash-out price should reduce this likelihood even further. However, we recognise that successful implementation of the proposals in practice will require careful design to ensure that all potential interactions have been considered. In particular, irrespective of whether the proposal to remunerate Non-Half Hourly (NHH) customers for providing involuntary DSR (i.e. the £5/hour and £10/hour payments to domestic and small business customers respectively) is implemented, scenarios will have to be examined to explore the different cash flows that could result in the event cash-out rises to VoLL.

This careful design will need to incorporate a large number of impacted parties, including suppliers and Distribution Network Operators (DNOs), and is likely to require significantly more industry involvement than other elements of the EBSCR (e.g. reducing the value of PAR or moving from dual to single cash-out arrangements). In addition to this, it is important that the design of similar arrangements under the Gas Security of Supply SCR is considered as there will be a number of parallels to electricity (albeit a number of clear differences as well). Therefore, this is an area that we suggest is likely to require significant work to implement via the BSC modification process.

One important question is whether demand disconnections and voltage control should be treated equally under the cash-out regime (i.e. fed into the cash-out calculation at the same price). At present, when Demand Control is required, NGET requests that DNOs reduce demand by a certain amount; we do not prescribe how this is done. However, it is clear that the impact on end consumers of demand disconnection is far greater than that of voltage reduction. Therefore, we feel that voltage control should be priced into cash-out at a level below that of demand disconnection in order to reflect this.

Top-down or bottom-up estimation of Demand Control volumes

Regardless of whether the level of PAR is set at 1 or 50, the exact volume of energy related Demand Control instructed is unlikely to be critical for the calculation of the System Buy Price (SBP) as it will automatically represent the marginal action. Therefore, a top-down approach is likely to be sufficiently accurate in this case. However, were a bottom-up approach to be applied to arrive at this value, it is unlikely that this would be available until a month, or more, after the event.

There are also likely to be second order impacts in areas such as adjusting supplier imbalance volumes and payments to suppliers (see below) as a small difference in how these are calculated could result in a large difference in imbalance exposure. Therefore bottom-up calculations would be preferable here although exactly how this is to be done will require significant industry engagement to ensure that no other critical impacts are missed and that parties are generally comfortable with the approach.

Adjusting supplier imbalance volumes

It is important that the suppliers of customers who have been disconnected have their imbalance position adjusted to reflect this as they could otherwise stand to receive large windfall gains. This is especially true in a world of single marginal imbalance prices and could potentially be of the order of £6000/MWh. Instead, given that they would have pre-contracted the volumes that are disconnected, they should be compensated at a figure similar to the current 'reverse' price (i.e. in a similar manner to how this problem is treated in the gas regime).

It is also important that consideration is given to treatment of supplier imbalances in the event that one of their customers has signed a demand-side contract as, if this is called, their position would change (i.e. lengthen).

Question 4: Do you agree with our assessment of the interactions with the CM and its impact on setting prices for Demand Control actions?

We agree that the proposed reforms to cash-out complement the proposed design and incentives of the Capacity Market (CM), recognising that this design and enabling legislation is currently subject to Consultation. The CM looks to ensure overall adequacy by providing a stable revenue stream to support investment in required capacity; capacity providers are required to deliver at times of system stress or face financial consequences. The proposed reforms to the cash-out price clearly support this incentive to deliver for consumers. The link in the penalty formulation to the prevailing cash-out price ensures that the total incentive on market participants is sufficient to encourage delivery without exposing participants to excessive penalties which would not change behaviour.

The proposed reforms to the cash-out arrangements encourage investment in flexible capacity, responding to short term price signals in the wholesale markets and being available to the SO within balancing mechanism timescales and via provision of balancing services. The CM auction is technology neutral, recognising that investment in flexible capacity is more efficiently supported by signals provided by near term market prices than prescriptive limits set out potentially five years in advance of delivery. The proposed design for Demand Control actions supports both participation in the CM itself and parallel provision of balancing services.

We also recognise the impact the proposed reforms have upon the risk and reward balance within the energy market and that uncertainty in policy outcome may increase costs of participation in the CM and the energy market. We feel it important that potential capacity providers have visibility of the final Policy decision and confidence in implementation timescale in good time to support a decision to enter the CM, to develop competitive bidding strategies and to minimise costs introduced due to regulatory risk.

Question 5: Do you agree that payments of £5/hr of outage for the provision of involuntary DSR services to the SO should be made to non-half-hourly metered (NHH) consumers, and for £10/hr for NNH business consumers?

We agree that it is desirable to remunerate those consumers who have suffered demand disconnection and this approach is broadly consistent with the arrangements that have recently been proposed in the gas industry. However we are concerned that the administrative costs associated with the process could potentially outweigh the benefits delivered.

In addition, we feel it is important to note that, while the SO instructs when Demand Control actions should be taken, these “involuntary DSR services” cannot be classed as a service which is provided to the SO as, for any such service to be useful, we have to have visibility and confidence in the delivery (in advance) in order to plan operation of the system accordingly. Instead, Demand Control is part of a procedure designed to preserve the integrity of the electricity network as a whole in times of system stress.

Question 6: Do you agree with the introduction of the Reserve Scarcity Pricing function and its high-level design? Explain your answer.

In our previous response we stated that, despite its shortcomings, the existing Buy Price Adjuster (BPA) mechanism should be retained. This was on the grounds that there did not appear to be an alternative solution available that was capable of better reflecting the true value of products, such as Short Term Operating Reserve (STOR), which are procured ex ante with the majority of the value of the contract contained in “Availability” rather than “Utilisation” prices. However, we can see the potential for benefits with the introduction of a Reserve Scarcity Pricing (RSP) function and, in particular, see value in the idea that such an approach may help to notify the market of a tightening system alongside system warnings such as NISMs, HRDRs and DCIs[3]. We are also satisfied that this proposal will not affect the current procedure for procurement of services such as STOR by the SO and support the fact that non-BM STOR use will be reflected in cash-out.

As set out in the National Grid consultation[4] on Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR), should these new Balancing Services be approved by Ofgem, we believe their use should feed into cash-out prices to further sharpen incentives on participants to balance their positions. This could possibly be achieved by incorporating them into the Reserve Scarcity Pricing function but this would have to be carefully considered to ensure, for example, that the price feeding into cash-out for SBR reflects its “last resort” status (i.e. the price should approach VoLL).

As SO, NGET would be responsible for maintaining and delivering some of the data feeding into the process, both in terms of how the curve is set up (based on parameters such as LOLP) and in terms of calculating the reserve levels that are fed into the function to derive the RSP price. This would also include processing the Maximum Export Limits (MELs) and Final Physical Notifications (FPNs) received from BM Units. Given the importance of accurate indications of system margin, and how this will rely on accurate submissions from market participants, it may be necessary for NGET to more closely monitor the accuracy of MEL and FPN submissions.

In order for the benefits described above (in terms of informing the market of reducing reserve levels in such a manner that is likely to incentivise additional capacity coming forward) to be delivered, it is vital that the optimum trade-off between information provision and accuracy is reached. Therefore, we believe that a degree of industry engagement is required in order to design an approach that adequately captures and addresses the relevant risks and promotes the benefits. This is most likely to take the form of an industry workgroup set up under the BSC to implement the required change based on policy direction from Ofgem.

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[3] Notification of Inadequate System Margin, High Risk of Demand Reduction and Demand Control Imminent respectively

[4] http://www.nationalgrid.com/NR/rdonlyres/F3F35BA1-8FCA-4206-9234-85D59B2ADB66/62904/FinalProposalsConsultationDSBRSBR10thOctober2013Final1.pdf

It is clear that this policy decision is unlikely to be as prescriptive as those related to PAR level and single / dual imbalance prices. However, we believe it would be highly beneficial to see more detail than is currently available in relation to how Ofgem envisage the solution operating in practice. This is to minimise the amount of time required for the workgroup to devise a proposal and to reduce the risk that this proposal is not deemed acceptable by Ofgem which would also result in further delays.

Question 7: Do you agree with our rationale for a move to a single price, and in particular that it could make the system more efficient and help reduce balancing costs? Please explain your answer.

The analysis presented by Ofgem suggests that a single imbalance price would reduce the administrative costs associated with balancing across the market and also that it could help mitigate the cost of balancing for small independent market participants (i.e. weaker balancers) relative to large players (i.e. stronger balancers) as a result of how Residual Cash-flow Reallocation Cash-flow (RCRC) is treated. We are supportive of any initiative which reduces overall costs to end consumers and also which improves competition in energy supply and generation. We therefore agree with Ofgem that such a move should have the effect of mitigating risks for market participants associated with a reduced level of PAR.

However, we continue to have concerns regarding the potential incentive to self-balance that moving to a single imbalance price could create. In our response to the Initial Consultation, we expressed concern that a single cash-out price may incentivise market participants to act on their expectation of the Net Imbalance Volume (NIV) to attain an energy position in the opposite direction to that of the system. This could result in their achieving a more favourable system imbalance price than could be attained by trading this volume in the near-time market. We welcome actions taken either to self-balance or to gain from 'opposite imbalance' as long as these actions take place prior to Gate Closure as this should, in theory, aid our efforts to balance the system in real time. However, if unilateral actions were taken by market participants post-Gate Closure, we foresee increased risks in balancing the system efficiently (potentially by exacerbating system constraints) which could significantly outweigh the anticipated benefits of a single imbalance price.

In addition, we agree with the conclusion from the Policy Decision that an information imbalance charge would not be an appropriate solution, since we would not want to risk placing financial penalties around information accuracy which may lead to compliance being considered as a commercial trade-off rather than a Grid Code obligation. However, it may be useful to review how to make best use of the sanction arrangements in place currently to ensure information is submitted as accurately as possible. This will ensure both that processes allow rigorous investigation of any parties suspected of intentionally submitting inaccurate data or intentionally deviating from information provided, and that suitable enforcement actions are available if required.

With regard to the argument that moving to a single imbalance price could increase the incentive to spill, and therefore increase balancing actions for the SO as a result, we do not see this as being a likely consequence. Whilst for each individual market participant it might appear to make commercial sense to go into cash-out with a long position in the event that they foresaw a short system, if enough parties applied this approach the likelihood is that the system length would increase and potentially even flip from short to long (even if it is further assumed that the initial forecast was sound). In this event, it would have been better to have sold the energy prior to gate closure and gone into cash-out with a balanced position as the price achieved would have been higher than the resulting SSP. Therefore, in theory, this would cease to be a viable strategy when considering the system as a whole and so we would hope that the market would quickly readjust. Furthermore, when considering the impact on renewable generators such as wind farms, the move to a single imbalance price (especially in conjunction with a reduced level of PAR) could incentivise more accurate balancing as the spilling strategy currently used becomes less of a "safe" option as the risk of negative prices increases. This would be a benefit for the SO as it could lead to more accurate FPNs from these renewable generators.

Another possible unintended consequence of moving from dual to single imbalance prices is that, in the event that parties consider it commercially advantageous (based on their forecast of system length) to attempt to go into cash-out in the opposite direction to NIV rather than trade in the spot markets to balance their position, it could have a detrimental effect on near-real time liquidity. As mentioned above, this effect could well be outweighed by the potential increase in near-time liquidity driven by a move to more marginal imbalance prices. However, we feel it may be prudent to consider the interaction of these policy proposals on liquidity given its importance in designing an efficient and competitive market – as well as the recent work carried out on the subject under the proposals for a 'Secure and Promote' licence condition.

Implementation issues

In a similar manner to that described in our response to Question 1 (i.e. reducing PAR) we believe that, should a move to a single imbalance price be proposed in the Final Policy Decision, its implementation should be accelerated. This assumes both that the system / procedural changes required to implement the move to a single price are non-complex and that the final policy decision made would be such that no additional industry debate is required (i.e. a binary 'yes or no').

The first benefit of this approach is that it would mitigate the risk of delays that might be evident were all the policy proposals contained in the package to be implemented together (e.g. due to complications with elements such as the RSP function and the costing of Demand Control actions). Additionally, if it is assumed that implementation of the PAR reduction is accelerated, it would also ensure that any interaction between these two policies is maintained (i.e. that the move to a single imbalance price mitigates some of the risks to market participants associated with more marginal imbalance prices).

Question 8: Do you have any other comments on this consultation, including on the considerations where we did not propose any changes?

Interaction with the gas cash-out arrangements

As National Grid plc has interests in both the electricity and gas markets, we are particularly interested in areas where there may be incompatibilities between the two regimes. We believe that, without careful consideration, there is the possibility for inconsistencies to develop in the event that a gas emergency was to coincide with a tight electricity system[5]. This is due to the different VoLLs that are expected to be applied across gas and electricity: under Stage 3 of a gas emergency, it is currently proposed that VoLL for non daily metered demand isolation is set at an administrated level of £14/therm on days of new isolation, while the electricity VoLL applied under cash-out (£6000/MWh) corresponds to a value of ~£85/therm for a 50% efficient Combined Cycle Gas Turbine (CCGT).

This difference suggests that, in theory at least, domestic gas customers would be disconnected ahead of CCGTs despite the fact that reconnecting gas customers who have been isolated is much more expensive and time-consuming than it is for electricity (as each site requires manual reconnection) and that gas doesn't fail-safe in the way that electricity does. Whilst this would not happen in practice as a result of the NGG Safety Case (as the stages of a gas emergency would disconnect large daily metered demand such as CCGTs prior to isolating domestic consumers), it does highlight an inconsistency between the two industries in the event that a gas emergency is declared (until this emergency stage no administrative VoLL is applied) as the CCGT is exposed to the spread (i.e. approximately £71/therm) between the two prices.

[5] A gas emergency is indeed likely to lead to a tight electricity system given the volume of gas-fired power stations in the generation mix.

The Gas SCR proposal includes a Demand Side Response (DSR) process with the potential for CCGTs to bid in at an uncapped price. This may result in some CCGTs bidding into the DSR at levels that hedge their electricity exposure (i.e. by bidding in at a price which corresponds to this exposure). This would mean that, if the reduction in CCGT demand would assist in avoiding an emergency, the Gas SO would accept this bid. This would result in the CCGTs perfectly hedging their electricity exposure and, therefore, the interaction between the two proposals may not result in any additional gas fuel security for CCGTs.

In addition, NGG has worked hard over recent years to introduce contestability in the provision of Operating Margin (OM) services. Some of the new providers for this service have been CCGTs offering a “turn down service”. Given sharper levels of electricity balancing cash-out prices, it is possible that these providers may withdraw from the OM market. While this may be good for the electricity system in the sense that these CCGTs will not be reducing output at short notice, it may have adverse implications for gas security of supply.

Other policy proposals

Moving to a single, as opposed to dual, imbalance pricing regime effectively has the same financial (although not volume-related) impact on relevant market participants as moving from separate consumption and production accounts per Balancing Mechanism Unit (BMU) to a single account as it allows imbalances in opposite directions to be netted off against each other. It also does this in such a way that all market participants benefit as opposed to it solely benefiting large portfolio players[6]. Therefore, we are comfortable that no changes are proposed to the ‘production / consumption’ account structure.

In terms of Gate Closure, we feel that moving to a period of less than an hour may be too restrictive to our balancing activity, as it would severely restrict the plant that would be available for us to instruct to ramp up or down to help balance the system. Therefore, we are comfortable that no change is proposed at present.

Question related to the accompanying Impact Assessment:

Question 9: Do you have any comments regarding any of the three approaches we have taken to assess the impacts of the cash-out reform packages?

Ofgem’s Impact Assessment and the supporting Baringa report provide a comprehensive set of analysis with which to assess the impacts of these cash-out proposals. We recognise the complexities involved in evaluating the likely impacts of the reform packages. With the numerous interacting factors that have the potential to drive parties’ behaviour, both directly related to the cash-out polices and externally developing in the wider industry, any modelling will be necessarily constrained by certain assumptions. Therefore it is appropriate to consider multiple approaches, both quantitative and qualitative, to impact assessment, as Ofgem have done in their appraisal.

Whilst the historical analysis is important for completeness, the output of the Forward Modelling assessment is of particular value since it takes account of how parties’ behaviour will adapt in response to the policy packages.

Simulating how parties respond to policy changes designed to drive behaviours is inevitably subject to limitations; especially where the changes to incentives are interactive and unprecedented in given external conditions. Of particular pertinence is how market participant behaviour evolves with respect to short term balancing actions and in response to longer term investment decision signals. The potential risk that, under a single cash-out price, parties might be incentivised to deviate from their FPNs after Gate Closure is recognised in the commentary of Risks and Unintended Consequences. The Cost-Benefit Analysis (CBA) recognises that several influences contribute to investment decisions but, for the purposes of this modelling, they are based on signals provided by near term market prices.

[6] See paragraph 4.67 of the Consultation Document.

Whilst the qualitative reasoning provided to mitigate concerns over these uncertainties is logical, the specific impacts on how individual participant strategies will change are unknown. Therefore, a more staged approach to implementation, both in terms of the policy package as a whole and the PAR volume (as recommended above), should lessen the risks of distortions to behaviour in ways that the modelling has not been built to indicate.

Question 10: Do you agree with the analysis of the impacts contained in this IA? Do you agree that the analysis supports our preferred package of cash-out reform? Please explain your answer.

Given the assumptions and simplifications made in the Impact Assessment, the analysis of the impacts appears reasonable.

The stated key objectives of the EBSCR are: to incentivise an efficient level of security of supply; to increase efficiency of electricity balancing; and to ensure balancing arrangements are compliant with the EU Target Model (TM) and complement DECC's EMR CM. Examining the analysis against these criteria:

- *Security of supply*

Packages 3 and 5 provide the minimal anticipated volume requirements for Demand Control actions in 2030 (as per the Expected Energy Unserved (EEU) in Table 6).

- *Efficient balancing*

Depending on the scenario assumed and the year (2020 or 2030), packages 2, 4 and 5 provide the maximum overall £/year benefit in the Cost-Benefit Analysis. This provides clear support for the move to a single cash-out price through the demonstrable gains that can be achieved by reducing costs of imbalance relative to dual cash-out price packages.

- *Compatibility with EU Target Model and EMR CM*

We are satisfied that the EB SCR policies proposed in this package complement the ongoing electricity EU TM and EMR policy considerations.

In summary the analysis points towards the combination of policies intended to sharpen the cash-out price (marginal price, costing Demand Control and introducing the RSP) as being most effective in incentivising investment in the required capacity, whilst the single cash-out price mitigates certain impacts these policies might have on net imbalance costs. Therefore we agree that the analysis supports Ofgem's preference for package 5. In addition, we note that whilst the anticipated volume of EEU increases under package 4 compared to package 5 (the difference between the two packages being that 4 has a 50MWh instead of 1MWh PAR), package 4 as an interim solution would still present a significant improvement against 'Do Nothing'.

Question 11: Do you agree with the key risks identified and the analysis of these risks? Are there any further risks not considered which could impact on the achievement of the policy objectives? Please explain your answer.

The key risks highlighted broadly cover the main considerations associated with implementation of these policy packages. We provide some further comment on particular risks below.

Risk of pollution of cash-out prices

It may be worth noting that, whilst Table 12[7] is useful in demonstrating that for 78% of periods a 1MWh PAR would have had multiple actions at the price which set the cash-out price, had one of these actions been at an anomalous (and more extreme) price then that would have been the single price setting action. Hence, a single unrepresentative action (if more extreme) would by its nature be the

[7] Page 34 of the Impact Assessment

price setting action under a 1MWh PAR. As set out in our response to Question 2, the track record for SMAF mis-flagging feeding into system prices indicates that these instances are uncommon but possible. Furthermore, post-event corrections of mis-flagged actions would alleviate these issues. Acknowledging that a 1MWh PAR would increase the potential exposure of system prices to single actions, introducing a step to 50MWh PAR (as a precursor to a 1MWh PAR) would mitigate risks of any unexpected consequences by allowing an interim appraisal of likely impacts.

Accuracy of information submissions

As per our response to the Initial Consultation, as SO, a key concern related to the move to a single cash-out price is that it could potentially incentivise intentional deviations from FPNs by participants seeking to achieve a better price for their energy via the imbalance pricing regime than that available on the market. This is because it could cause us uncertainty in our role of balancing the system. This is addressed in the Impact Assessment by pointing towards the likelihood of a party's ability to successfully forecast the Net Imbalance Volume and that it is unlikely that it would prove to be a sustainable strategy. In the absence of experience that would provide quantitative analysis to indicate how parties behave in these conditions, we are satisfied with the reasoning presented to support confidence in a single cash-out price. However, as stated in the Impact Assessment, "The impact of a single price on party incentives is uncertain" and therefore we would consider it a known risk to be monitored should the proposed policy be implemented.

Likewise, as we have stated in our response to Question 6, the accuracy of MEL submissions will be fundamental to the precision of the capacity margins which feed into the RSP function and the reserve prices that are subsequently generated. This is a further information risk that should be recognised along with FPN accuracy.

Interaction with the Gas SCR

Whilst the Draft Policy Decision identifies the Gas SCR as a key interaction, and treatment of gas-fired generation as a key consideration, it is not listed within the key risks of the Impact Assessment. To reiterate our concerns expressed in Question 8, it is imperative that logical consistencies are maintained between arrangements in the gas and electricity regimes and, in establishing policy details, careful consideration should be given to interactions between the two.

Question 12: What if any further analysis should we have undertaken or presented in this document? Do you have any additional analysis or evidence you would like to contribute to support the development of the EBSCR towards its Final Policy Decision?

As stated in Question 9, Ofgem's Impact Assessment and the Baringa report provide a sufficient breadth of analysis given the constraints in terms of time, resources and the intention for simplicity and transparency where possible. However, if further analysis were to be undertaken on potential impacts, the following areas may provide valuable insights.

The Impact Assessment notes concerns raised by stakeholders cautioning that the bankability of more volatile cash-out price signals may not generate the level of investment anticipated by modelling assumptions of rational economic behaviour. Whilst we are not close to all the considerations involved in the decision making process for investment in generation capacity, such as the extent to which a low probability occurrence of a high cost incident provides a sufficient signal for additional investment, it might be valuable to capture input on this from industry. The Baringa report sets out the alternative modelling options that were considered before determining on the top down simulation model. Whilst we agree with the reasons provided for electing for the 'top down' simulation model, the Bottom-Up agent-based model, if designed appropriately, could provide indications of how parties might adjust responses and strategies over time to optimise their positions. Recognising that feeding such insights into quantitative modelling may prove technically difficult, further consideration of this area could be informative even if it was based solely on qualitative evidence gathered from industry.

The Impact Assessment provides a view of the estimated average annual bills under the package proposals for the domestic consumer and in all cases the impacts appear negligible. A view is also provided on the distributional effects of the changes to different types of market participants (smaller parties are likely to be more exposed to imbalance risk from polices to sharpen the cash-out price). Therefore, whilst the average customer bill may be relatively unchanged, the volatility of customer bills associated to different suppliers who are better or worse at balancing might provide insights for when determining any policy design.

We do not have any additional evidence to contribute to the development of the EBSCR at this time.